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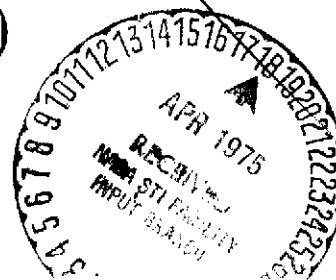
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**UNITED STATES TRANSPORTATION
FUEL ECONOMICS (1975-1995)**

Arthur D. Alexander III
Ames Research Center
Moffett Field, Calif. 94035



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16. Abstract <p>This report describes and evaluates United States transportation fuel economics in terms of fuel resources options, processing alternatives, and attendant economics for the period 1975-1995. The U.S. energy resource base is reviewed, portable fuel-processing alternatives are assessed, and selected future aircraft fuel options — JP fuel, liquid methane, and liquid hydrogen — are evaluated economically. The primary emphasis of this study is placed on evaluating future aircraft fuel options and economics to provide guidance for future strategy of NASA in the development of aviation and air transportation research and technology.</p> <div style="text-align: center;"> <p>Reproduced by NATIONAL TECHNICAL INFORMATION SERVICE U.S. Department of Commerce Springfield, VA. 22151</p> <p>PRICES SUBJECT TO CHANGE</p> </div>		
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TABLE OF CONTENTS

	Page
SUMMARY	1
INTRODUCTION	1
ENERGY CONSUMPTION IN THE UNITED STATES	3
UNITED STATES CONVENTIONAL FUEL RESOURCES	5
Fossil Fuel Reserves	5
CONVENTIONAL FUEL PROCESSES	6
Petroleum Based Fuels	6
Processing to JP aircraft fuel	6
Processing to hydrogen	7
Processing to methane	8
Natural Gas Based Fuels	8
Processing to methane and hydrogen	8
Water Based Hydrogen	9
Processing to hydrogen	9
UNCONVENTIONAL FUEL PROCESSES AND ECONOMICS	9
Oil Shale Processing	9
Process description	9
Oil shale process flow diagram	10
Oil shale processing economics	10
H-Coal Liquefaction	11
Process description	11
H-Coal liquefaction process flow diagram	11
H-Coal liquefaction process economics	12
Organic Waste Liquefaction	12
Process description	12
Organic waste liquefaction process flow diagram	13
Organic waste liquefaction economics	13
In Situ Coal Gasification	14
Process description	14
In situ coal gasification process flow diagram	14
In situ coal gasification economics	15
Coal Gasification	15
Process description	15
Bi-gas coal gasification flow diagram	16
Bi-gas coal gasification process economics	16
Solar Algae Gasification	16
Process description	16
Solar algae gasification flow diagram	17
Solar algae gasification process economics	17

PROJECTED AIRCRAFT FUEL ECONOMICS	18
JP Aircraft Fuel Economics	18
Off-shore crude oil reserves	19
Economics of JP fuel from shale oil	19
Economics of JP fuel from organic waste syn-crude	20
JP fuel cost summary	20
Liquid Methane Aircraft Fuel Economics	20
Liquid Hydrogen (LH ₂) Aircraft Fuel Economics	21
Methane steam reforming LH ₂ economics	21
Coal gasification LH ₂ economics	22
Electrolytic LH ₂ economics	22
LH ₂ fuel cost summary	23
CONCLUDING REMARKS	23
REFERENCES	25

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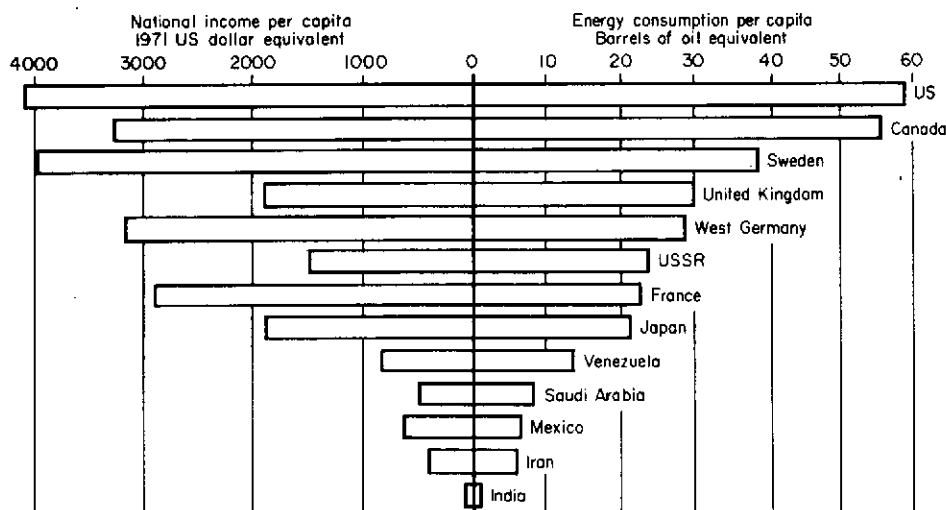
SUMMARY

This report describes and evaluates United States transportation fuels in terms of fuel resource options, processing alternatives, and attendant economics for the period 1975-1995. A primary assumption – that future U.S. energy resource independence is an economic imperative – serves as a fundamental study guideline.

U.S. domestic energy resource supply and demand is reviewed over the timeframe 1975-1995. Fuel-processing alternatives are assessed to provide a basis for comparing and selecting those processes that promise optimum economy and continuity of supply for the future. The detailed economics of JP fuel, liquid methane, and liquid hydrogen are evaluated and presented to highlight fuel issues and possible impacts on future strategy of NASA aviation and air transportation research and technology.

INTRODUCTION

It is generally accepted that a strong relationship exists between per capita energy consumption and personal income (fig. 1) (ref. 1). The fact that the United States has consistently consumed more energy and has produced more income per capita than any other nation in the world is vitally



Source: Standard Oil Company of California Economics Department – 1973

Figure 1.—Energy is affluence.

important when viewed in the global context of dwindling recoverable oil and gas reserves. It is of greater significance that other less affluent nations will be competing more aggressively in the future for their share of these important fossil fuel resources, further intensifying the U.S. supply problem. Thus, the U.S. must make numerous fundamental decisions concerning energy resources, attendant economics, and the very lifestyle they support.

Currently, the United States imports over 1/3 of its crude oil (ref. 2). Future U.S. petroleum demand projections (refs. 3 and 4) indicate that, by 1995, oil imports could constitute as much as 73 percent of our domestic oil needs, equivalent to an annual deficit of some \$50 billion per year by 1995 (fig. 2). Unless the U.S. rapidly develops its offshore (continental shelf and slope), deep-water oil reserves, most of this oil would have to be purchased from the Organization of Petroleum

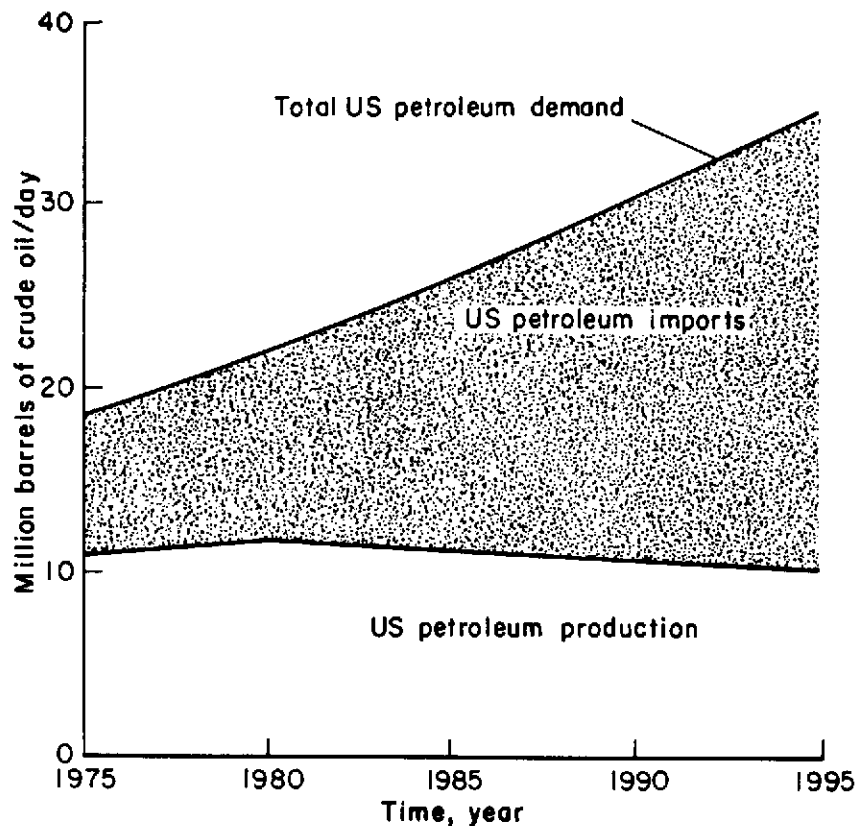


Figure 2.—U. S. petroleum supply/demand (1970-1995).

Exporting Countries (OPEC), composed of the North African and Persian Gulf countries and Venezuela. The 1973 OPEC oil embargo added significantly to the short fall in crude oil supply and drove the average price of foreign crude up about 250 percent (from \$3.60 to \$9.00 per barrel). The political posture of these nations and their limited oil reserves raise serious questions as to the continuity and price stability of future oil and gas supplies. Further, because of rapidly dwindling natural domestic gas reserves (refs. 5-9), the United States is investing major capital (up to \$11 billion by 1985) in developing shipping capacity, liquefaction capacity, and port facilities so that liquefied natural gas (LNG) can be imported from Algeria and the recently proven North Atlantic fields. Again, the present political posture of Algeria is not conducive to assurance of an uninterrupted supply of LNG. Further, even if foreign imports could be assured for the future, the

balance-of-trade deficits could lead to serious economic problems for the U.S. The portable fuel alternatives for the United States to attain energy self-sufficiency are as follows: (1) increase domestic crude oil and gas supply through offshore outer continental shelf (OCS) resources, (2) develop unconventional processes for fuels similar to petroleum-based fuels, and (3) develop unconventional processes for fuels dissimilar to petroleum-based fuels. This report describes the processes, the availability of raw materials, and the related economics of the latter two alternatives. For comparison, the conventional crude oil and natural gas processes are also described.

ENERGY CONSUMPTION IN THE UNITED STATES

The total U.S. energy consumption in 1970 was 72×10^{15} Btu. Table 1 indicates the resource distribution pattern across the four consuming sectors projected for the years 1970, 1985, and 2000. These projections were made by the National Petroleum Council and the U.S. Bureau of Mines prior to the OPEC oil embargo and the resulting energy supply crisis. There is no assurance, therefore, that these projections correctly reflect future U.S. energy resource demand.

TABLE 1.— U. S. ANNUAL CONSUMPTION OF ENERGY BY VARIOUS CONSUMING SECTORS^a
(In units of 10^{15} Btu)

Consuming sector	Coal	Petroleum ^b	Natural gas	Total fossil fuel	Nuclear power	Hydro-power	Total gross energy input	Percent of total
1970								
Household & commercial	0.280	5.519	7.218	13.017	----	----	13.017	(18.1)
Industrial	5.054	7.128 ^c	12.972 ^d	25.154	----	----	25.154	(34.9)
Transportation	----	16.593	0.629	17.222	----	----	17.222	(23.9)
Electrical generation	7.728	1.926	4.049	13.703	0.242	2.677	16.622	(23.1)
Total (Percent of total)	13.062 (18.1)	31.166 (43.3)	24.868 (34.5)	69.096 (95.9)	0.242 (0.3)	2.677 (3.7)	72.015 (100.0)	(100.0)
1985								
Household & commercial	0.091	6.984	11.661	18.736	----	----	18.736	(13.0)
Industrial	6.048	14.492 ^c	20.886 ^d	41.406	----	----	41.406	(28.8)
Transportation	----	29.216	1.180	30.396	----	----	30.396	(21.1)
Electrical generation	16.929	5.642	6.412	28.983	21.187	3.118	53.288	(37.1)
Total (Percent of total)	23.068 (16.0)	56.334 (39.2)	40.119 (27.9)	119.521 (83.1)	21.187 (14.7)	3.118 (2.2)	143.826 (100.0)	(100.0)
2000								
Household & commercial	----	0.494	19.066	19.560	----	----	19.560	(10.9)
Industrial	2.000	18.725	30.284	51.009	----	----	51.009	(28.5)
Transportation	----	35.236	1.000	36.236	----	----	36.236	(20.2)
Electrical generation	24.179	0.861	4.128	29.168	38.067	5.040	72.275	(40.4)
Total (Percent of total)	26.179 (14.6)	55.316 (30.9)	54.478 (30.4)	135.973 (75.9)	38.067 (21.3)	5.040 (2.8)	179.080 (100.0)	(100.0)

^aSee references 3, 6 and 9.

^bConversion factor: barrels/day (B/D) \times 365 days/yr \times 5.8 million Btu/barrel

^cIncludes 3.953×10^{15} Btu of petrochemical feedstocks in 1970 and 8.812×10^{15} Btu in 1985.

^dIncludes 4.11×10^{15} Btu of gas raw material in 1970 and 4.399×10^{15} Btu in 1985.

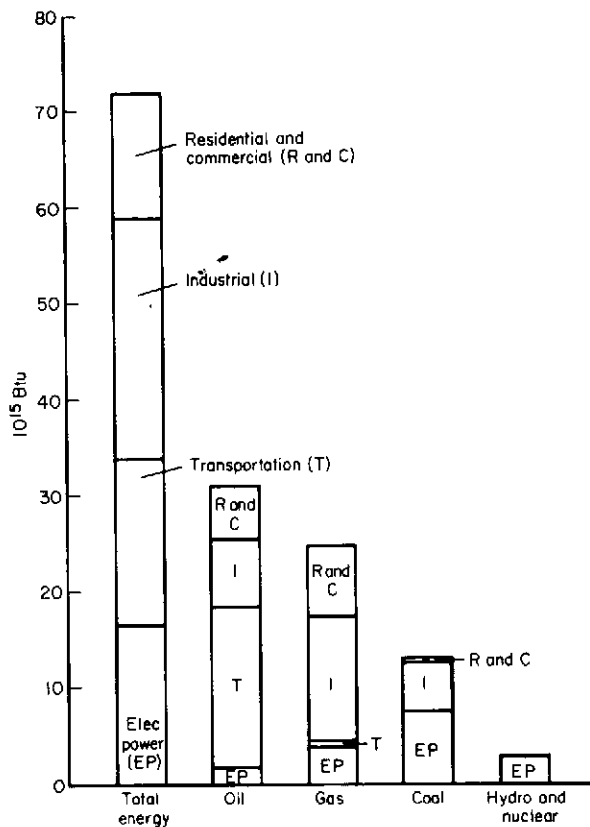


Figure 3.—1970 U. S. energy consumption by sector (refs. 3, 6, 9).

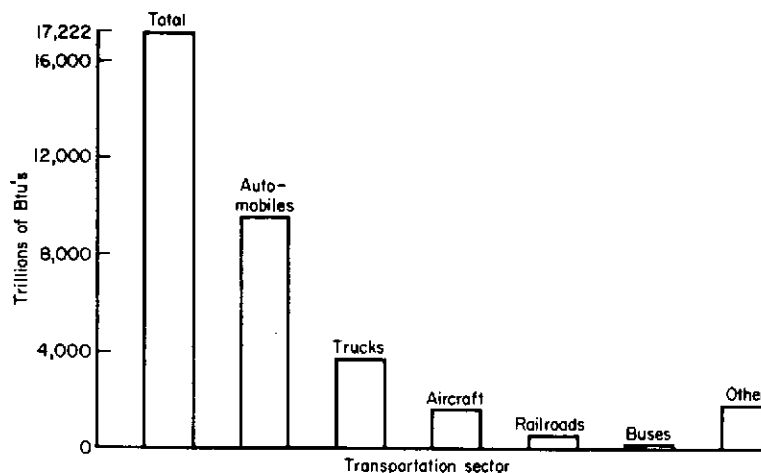


Figure 4.—1970 U. S. energy consumption by transportation sector (ref. 10).

Fuel consumption within the transportation sector in 1970 represented about 24 percent of the total energy consumed nationally (fig. 3). Figures 3 and 4 indicate that aircraft consumed less than 2.2 percent of total U. S. energy in 1970 and less than 10 percent of the fuels consumed by all of transportation (the automobile remains the primary fuel consumer). Note that petroleum resources alone provide the portable fuels required by most of our transportation systems. This study concentrates on describing and analyzing those alternative portable fuel resources and technological processes that offer the greatest economy, continuity of domestic supply and environmental advantage.

UNITED STATES CONVENTIONAL FUEL RESOURCES

Fossil Fuel Reserves

A review of the recoverable, domestic fossil fuel reserves and consumption of the world (see table 2) reveals that only coal represents a reasonable long-range energy source, unless, of course, deep ocean oil and gas technology is developed to enable commercial recovery of vast hydrocarbon deposits recently revealed along many of the seismic contours outlining the compressive tectonic

TABLE 2.— 1971 FOSSIL FUEL RESERVES AND PRODUCTION
(From ref. 5)

Nation	Coal		Crude Oil		Natural gas	
	Reserves 10 ¹⁵ Btu	Production 10 ¹⁵ Btu	Reserves 10 ¹⁵ Btu	Production 10 ¹⁵ Btu	Reserves 10 ¹⁵ Btu	Production 10 ¹⁵ Btu
United States	46,200	11.0	220	20.1	280	22.5
U. S. S. R.	90,675	9.7	350	16.2	635	7.5
Western Europe	2,100	4.6	50	0.6	170	3.5
Japan	420	0.7	3	0.7	1	0.1
China	22,250	8.6	---	---	---	---
World total	168,100	46.7	3275	103.2	1760	40.3

Conversion equivalents: 1 metric ton of coal = 22×10^6 Btu, 1 barrel of oil = 5.8×10^6 Btu, and
1 cubic foot of gas = 1×10^3 Btu.

plates comprising the earth's outer crust. Continental slope and captive deep-sea recoverable reserves are estimated at over 300 billion barrels of oil (1740×10^{15} Btu) and 700 trillion cubic feet of natural gas (700×10^{15} Btu) (refs. 15 and 16).

The National Petroleum Council established that U.S. domestic oil production, consisting of crude oil, condensate, and natural gas liquids, totaled 11.3 million barrels per day (B/D) in 1970, which was 31 percent of the total U.S. energy consumption. Despite the addition of an estimated 2.0 million B/D from the Alaskan North Slope and another 2.7 million B/D from new discoveries to be made after 1970, the total U.S. oil production from conventional sources in 1985 was estimated at only 11.1 million B/D and in 1995 at only 10.0 million B/D. Therefore, to meet growing demands for petroleum liquids, imports would have to increase more than threefold by 1995, reaching a rate of 25.0 million B/D, or 73 percent of the total U.S. demand by that year. In view of limited world oil reserves, it is unrealistic to assume that the United States will be able to meet its future oil demand through imports alone. Only conventional fossil sources, including domestic offshore, deep-ocean oil, domestic shale oil, and coal liquefaction, offer promise of economically meeting future U.S. oil demand. These alternative options are discussed in subsequent sections of this study.

U.S. demand for natural gas (ref. 17) may be expected to increase 75 percent in the period 1975 to 1995 from a level of 30.0 trillion standard cubic feet (TSCF) (30×10^{15} Btu) to a level of 53.0 TSCF (53×10^{15} Btu) in 1995 (fig. 5). According to the Bureau of Natural Gas, discovery and

development of new domestic gas reserves has been and will continue to be grossly inadequate to meet consumption demand for this clean inexpensive fuel. The ratio of proved reserves to annual production of natural gas has dwindled from 20.2 in 1960 to 13.2 in 1970, which includes the Alaskan North Slope reserve. Currently, the natural gas situation is critical; some distributors will not accept new customers because there are already peak load shortages and no promise of additional supplies. Besides the importation of liquefied natural gas, additional gas-supply alternatives include the production of synthetic gas from coal gasification and catalytic/thermal cracking of petroleum. Several major Western European countries have been using coal gasification processes to successfully and economically meet their increasing gas needs. The economics and supply stability of obtaining synthetic gas through coal gasification are very attractive and are reviewed in a following section.

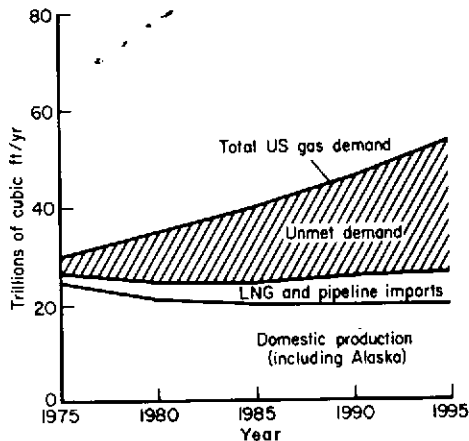


Figure 5.—U. S. gas supply/demand (1970-1995) (ref. 5).

Among domestic U.S. fossil fuel reserves, only coal and shale oil reserves offer significant promise for supplying the long-range energy needs of the United States, consistent with economic and environmental requirements. Currently, there are fundamental problems in developing and recovering these vast shale oil and coal reserves (discussed in later sections of this study). However, alternative technological processes are available for converting domestic coal into high-Btu-content, low-sulfur fuel oil or into high-Btu synthetic gas; urban and organic waste has been successfully converted into high-Btu-content fuel oil; and pilot processes are being developed to extract petroleum from domestic tar sands and oil. These processes are also described in subsequent sections.

CONVENTIONAL FUEL PROCESSES

Both present and future aircraft fuels are most economically derived from crude oil and natural gas resources, assuming their extended availability and low cost. The following sections describe the production of portable fuels from natural conventional resources.

Petroleum-Based Fuels

Processing to JP aircraft fuel— Crude oil is desalted, dehydrated, and heated to about 350°C before it is pumped into a fractional distillation tower (fig. 6). The hot oil feed is mixed with

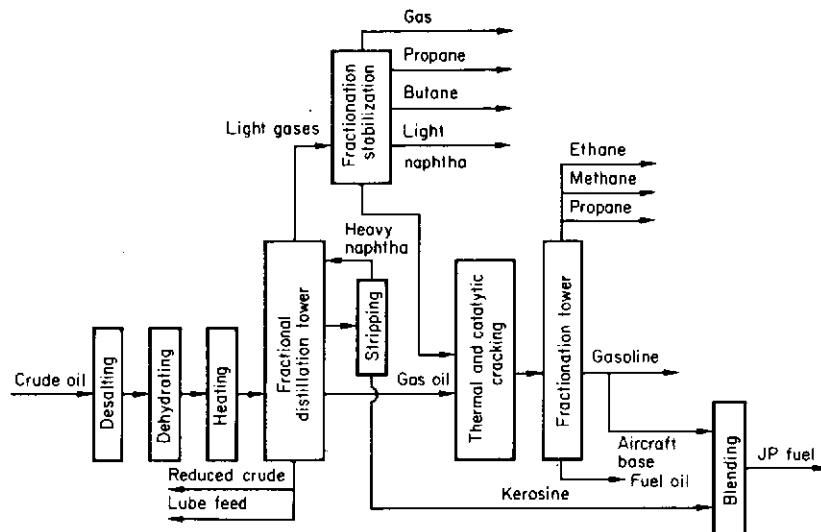
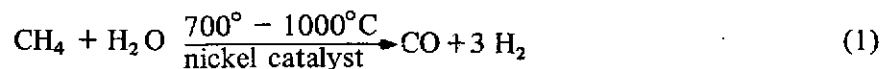


Figure 6.—Simplified flow diagram of crude petroleum refining.

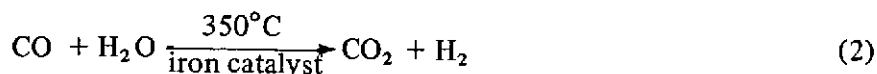
0.14 to 0.28 lb of steam per pound of crude oil to aid in separating the fractions. During distillation, the large crude oil molecules are fractionally split into volatile light gases (including methane and propane) that are drawn off the top of the distillation tower. The heavier liquid fractions containing the naphthas, kerosine, and gas oils are next drawn off, followed by the heavy lube oils. The kerosine is sent through a stripping column and subsequently blended with heavy gasoline fractions into the desired JP aircraft fuel. The liquid naphthas, containing most of the straight gasoline fraction (20 percent of crude oil volume) and gas oils, are further cracked into smaller molecular fractions and fractionated to yield additional gasoline, light volatile gases, and fuel oils.

Processing to hydrogen— Most of the some 100 billion cubic feet of U.S. hydrogen produced annually is derived from petroleum refinery products: light refinery gases, gasoline, fuel oil, and crude oil. The latter two, which are the heavy molecular fractions, are cracked to provide a high yield of the light gas fractions. Obviously, natural gas, rich in methane, is the preferred raw material source for hydrogen production, and petroleum light gases are a secondary source.

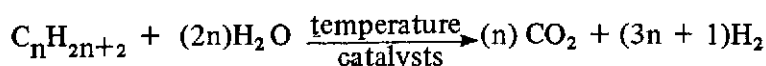
The light gas fractions are reacted with steam over a nickel catalyst at 700° to 1000°C to produce a mixture of carbon monoxide (CO) and hydrogen (H₂). The carbon monoxide is further reacted with steam at about 350°C over an iron catalyst to produce carbon dioxide (CO₂) and additional hydrogen. The catalytic steam reforming of light petroleum (or natural gas) reactions are: (Methane)



Further,



These step reactions are expressed empirically for the light hydrocarbon gases as



The carbon dioxide and hydrogen are normally separated by scrubbing the gaseous product mixture with monoethylamine ($\text{CH}_3\text{CH}_2\text{NH}_2$).

Processing to methane (CH_4)— The light volatile gases are derived from the distillation, cracking, reforming, fractionation, and stabilization processes in crude oil refining. The mixed gases are processed to remove moisture, carbon dioxide, and hydrogen sulfide. The main constituents of the dry gas are methane, ethane, propane, butane, ethylene, and propylene. The methane, ethane, and propane fractions can be isolated by selective liquefaction, taking advantage of the differences in boiling point among the mixture of gases.

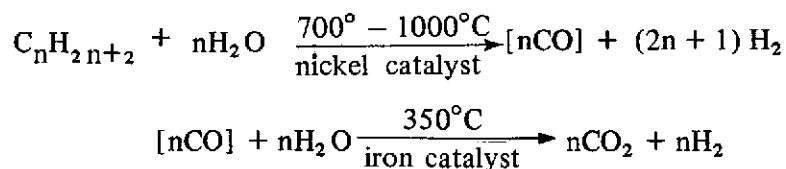
Since the petroleum light gases have a high heating value (about 1500 Btu/ft³), they are used extensively in refining operations and as a peak-load substitute for natural gas.

Should liquid methane be required in substantial volume for aircraft fuel, the petroleum distillation, cracking, and hydrogenation processes could be adjusted to yield a high fraction of the light gases. By analogy, straight crude oil distillation yields on the average only 20 percent gasoline; but, as gasoline demand increased, the larger-molecular-weight oils were cracked and fractionated to produce about a 50 percent yield of high octane gasoline. Additional light gas production from crude oil would require an expansion of pretreatment and liquefaction capacities at most refineries.

Natural-Gas-Based Fuels

Processing to methane and hydrogen— United States natural gas contains as much as 99.5 percent methane with traces of CO_2 and N_2 . By definition “wet” gas contains more than 0.1 gallon of gasoline vapor per 1000 ft³ (0.013 percent); “dry” gas contains less than 0.1 gallon of gasoline. There are no olefins or hydrogen in American gas. European and African natural gas typically contains 35 to 85 percent methane, 35 to 10 percent ethane, 20 to 3 percent propane, 5 to 1 percent butane, and 5 to 0 percent pentane. These gas mixtures may be fractionally liquefied under pressure after scrubbing to separate the liquid components (gasoline, etc.) and the undesirable hydrogen sulfide, nitrogen and carbon oxides. Domestic gas is the least expensive source of methane.

Catalytic steam reforming of natural gas is the most economic source of bulk hydrogen. The reactions are



The hydrogen and carbon dioxide are separated by scrubbing with monoethylamine before hydrogen liquefaction.

Water-Based Hydrogen

Processing to hydrogen— Electrolysis of sea water, $2\text{H}_2\text{O} \rightarrow 2\text{H}_2 + \text{O}_2$, generates hydrogen of very high purity (99.9 percent) and high-purity oxygen as a byproduct. Unless a large, inexpensive source of electricity is available, this method of producing hydrogen is very expensive (as discussed later). Another less expensive process is to pass steam over iron at 800°C , $\text{Fe} + \text{H}_2\text{O} \rightarrow \text{FeO} + \text{H}_2$.

UNCONVENTIONAL FUEL PROCESSES AND ECONOMICS

Alternative fuel-processing technologies are available for converting domestic coal into high-Btu-content, low-sulfur fuel oil or into high-Btu synthetic gas; urban and organic waste has been successfully converted into high-Btu-content fuel oil; and pilot processes are being developed to produce methane gas from algae and petroleum from domestic oil shale and tar sands. The following sections describe the most promising alternative fuel-processing technologies for deriving portable liquid and gaseous fuels, the estimated capital cost of each process, and the resulting fuel unit cost. Figure 7 summarizes the capital and product unit costs of the most promising alternative oil and gas processes.

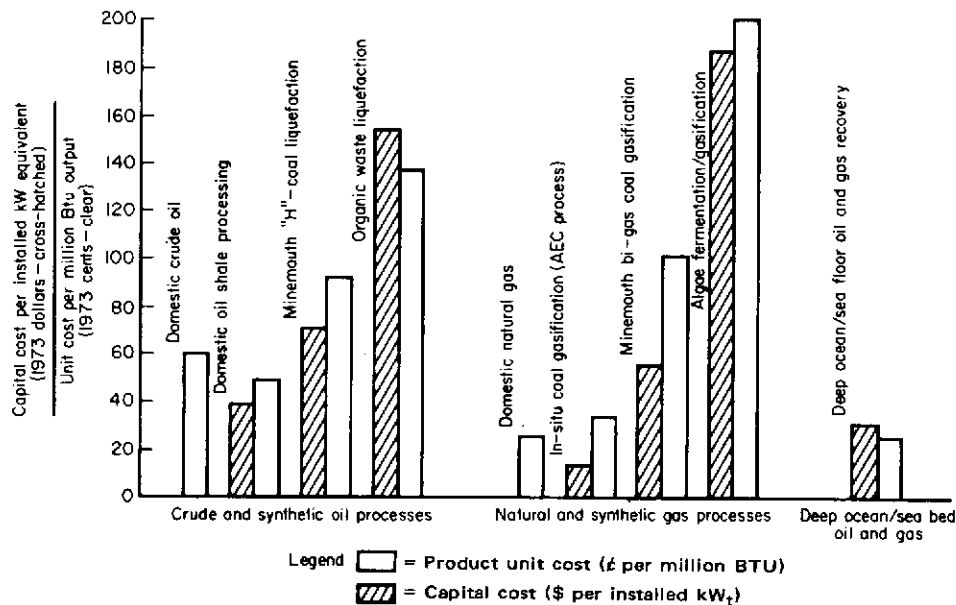


Figure 7.—Capital and unit costs for United States alternative oil and gas processes.

Oil Shale Processing

Process description (ref. 14)— Oil shale is a finely textured sedimentary rock containing the solid, largely insoluble, organic material known as kerogen. High temperatures decompose kerogen, yielding a raw oil substitute for use as a refinery feedstock. The principal deposits of high-grade oil shale (53 percent of known world supply) are found in Colorado, Utah and Wyoming. It has been estimated that these deposits contain 2 trillion barrels of oil, of which about 600 billion barrels are in rock assaying 25 gallons or more per ton (480 billion barrels on federal land, 120 on private).

The U.S. Bureau of Mines and TOSCO (The Oil Shale Corp.) have demonstrated successful "room-and-pillar" mining of thin shallow seams of oil shale. As yet, surface, or strip, mining techniques have not been attempted. "Cut-and-fill" mining is a second-generation approach to the underground mining of shale in which continuous mining machines remove the shale in layers, using spent shale as a floor on which to operate as higher levels of shale are removed. This method offers the advantage of not leaving 50 percent of the shale resource in place as does room-and-pillar mining.

The principal efforts to develop oil shale retorts for removing the oil from shale have been made by the Bureau of Mines, Union Oil Company, and TOSCO. The TOSCO II retorting process uses hot ceramic balls to heat the shale in a horizontal rotating kiln to 920°F (see fig. 8 and table 3). The balls are separated from the spent shale, reheated in a furnace fired with product gas, and returned to the retort. Flue gas from the ball furnace is used to preheat the shale. This process has been demonstrated at a rate of 1000 tons/day.

H-Coal Liquefaction

Process description (ref. 15)— Hydrocarbon Research, Inc., and the Office of Coal Research have developed a process for coal liquefaction by catalytic hydrogenation at low pressure. Crushed coal is mixed with recycle oil to form a slurry that is pumped together with hydrogen into a preheater operating at 2700 psi. The slurry and preheated recycle gas from the main reactor are pumped into the H-coal reactor, an ebullated-catalyst column. The catalyst, cobalt molybdate, settles below a point in the bed at which the liquid product is drawn off to a hot atmospheric pressure flash drum.

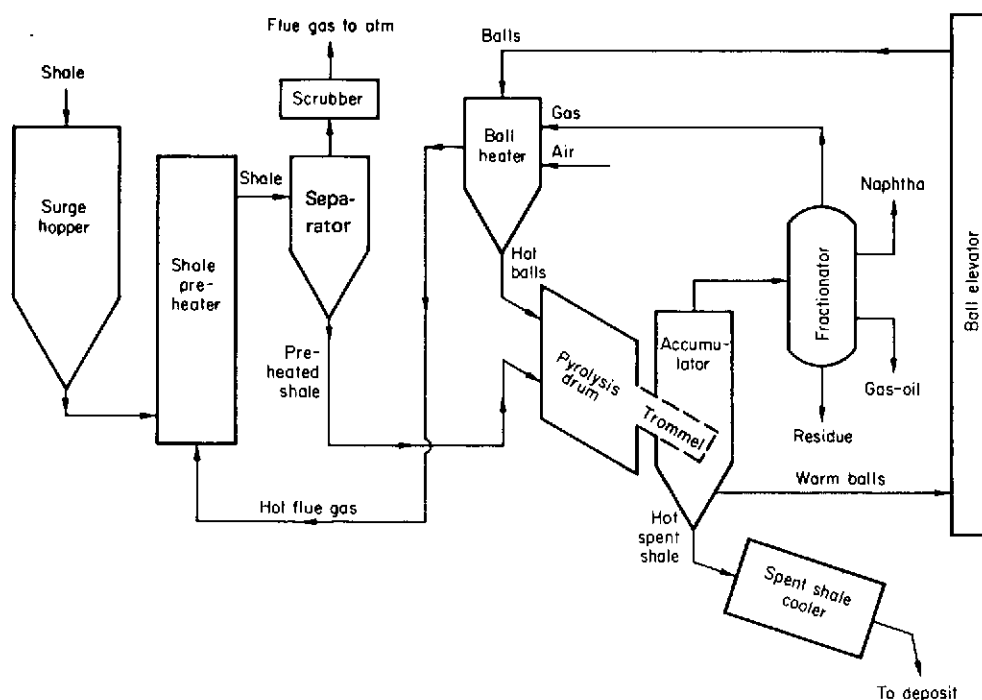


Figure 8.—Flow diagram of oil shale process.

TABLE 3.— OIL SHALE PROCESSING ECONOMICS
(1973 dollars for a 50,000-bbl/d plant)

Capital investment		Annual operating expenses		
Item	Cost \$, Million	Item	Oil cost	
			\$, Million	\$/Million Btu
Shale mine & equipment	29.3	Mining operations	13.1	0.128
Shale preparation & retorting	35.9	Retorting & refining	10.9	.107
Coking & by product process	14.4	Capital charge (20% of investment)	25.6	.250
Hydrofining & H ₂	27.5	Total expenses	49.6	0.485
Offsite & facilities	21.8			
Total capital investment	128.9			
(\$ per installed kW _t ^a =	38.0)			

^akW_t = kilowatt thermal

In the flash drum, the product separates into an overhead stream that is further separated by distillation, and a bottoms stream that is split, part of which goes into a vacuum-flash drum and part to a return line to the initial slurring operation. The bottoms vacuum flash drum further separates the product into an overhead vacuum product and a bottoms slurry product.

Uncondensed gas containing most of the coal sulfur as hydrogen sulfide (H₂S) is sent to a naphtha recovery operation, then to acid-gas removal, and finally to the hydrogen plant with other fuel gas. The H-coal products are subjected to further refinery operations. The char-oil product containing unconverted solids can be used either as a fuel or it can be subjected to carbonization to obtain additional liquid product (see fig. 9 and table 4).

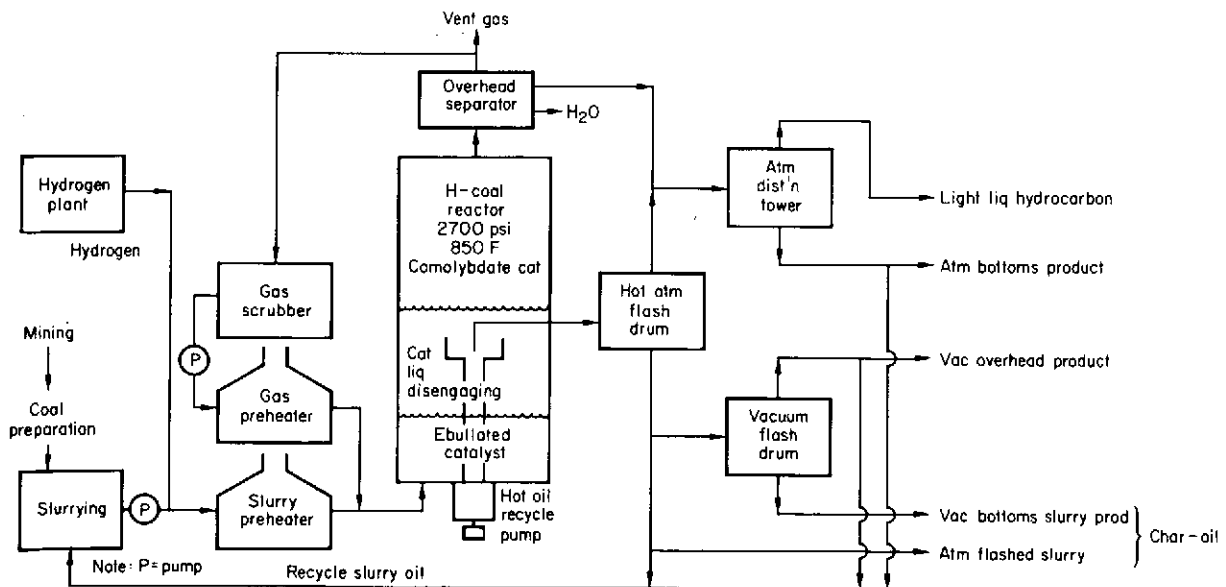


Figure 9.—Flow diagram of H-coal liquefaction process.

TABLE 4.— H-COAL LIQUEFACTION PROCESS ECONOMICS
(1973 dollars for 100,000 bbl/d oil product)

Capital investment (estimated)		Annual operating expense		
Item	Cost \$, Million	Item	Oil cost	
			\$, Million	\$/Million Btu
Coal preparation & feeding	40.0	Coal @15¢/Million Btu	24.0	0.114
Hydrogenation plant	180.0	Operation & maintenance	18.0	.086
H-Coal liquefaction plant	350.0	Overhead & taxes	30.0	.143
Offsite & utilities	30.0	Capital charge (20 percent of inv)	120.0	.572
Total capital investment	600.0	Total expenses (Coal @ 30¢/Million Btu)	192.0	0.915
(\$/Installed kW _t =	70.5)	Total expenses	216.0	1.029

Organic Waste Liquefaction

Process description (ref. 16)— There are essentially two kinds of solid wastes — inorganic and organic. Organic wastes are principally compounds of carbon, hydrogen, and oxygen. Although urban wastes constitute a huge source of organic material, other replenishable and continually increasing sources of organic solid waste, including agricultural, are adding significantly to the glut spreading over the land. Not only can essentially all of these organic wastes be recycled, but they can furnish much of our energy in the form of low-sulfur liquid fuels.

About 3 billion tons of various solid organic wastes are generated yearly in the United States. Agricultural wastes total 2.5 billion tons annually, of which about 2 billion tons are manure. The total urban wastes generated (including domestic, municipal, industrial, and commercial) are 400 million tons per year. The population is rising and so is the amount of solid wastes rejected per person. Discards collected by private and municipal agencies have almost tripled in the last 40 years, from 2.2 lb to 6.0 lb per person per day. It is predicted that this latter rate will double long before the end of this century.

The Bureau of Mines has developed a process for converting solid organic wastes to a low-sulfur oil potentially suitable for use by powerplants or for conversion to gasoline and diesel fuels. These organic wastes have been converted to oil by reaction with carbon monoxide and water in a reactor column at temperatures of 350° to 400°C and pressures near 4000 psig in the presence of various catalysts and solvents. Organic waste conversions of 90 percent and better (oil yields of 40 to 50 percent) have been obtained (see fig. 10 and table 5).

Two billion tons of waste per year, containing about 50 percent organic matter, could yield some 2 billion barrels of oil annually — about 50 percent of the 1970 U.S. demand for oil. Fundamentally, this process is a means to utilize solar energy which is, of course, the basis of cellulose production.

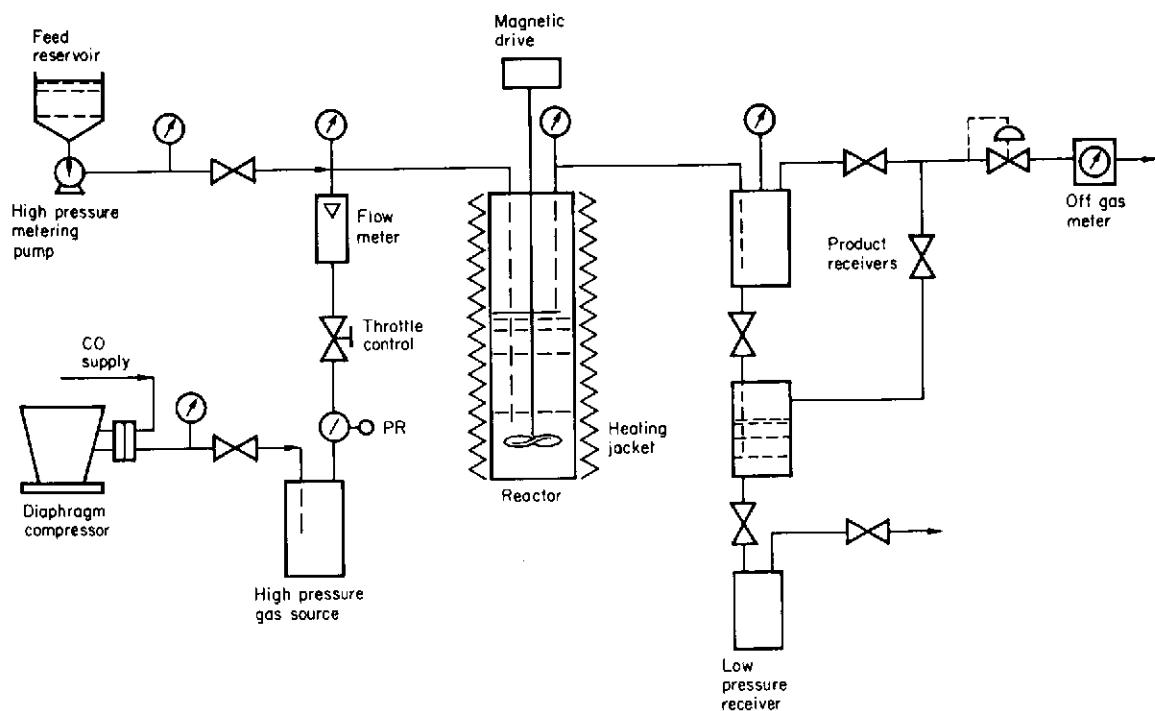


Figure 10.— Flow diagram of organic waste liquefaction process.

TABLE 5.— BUREAU OF MINES ORGANIC WASTE LIQUEFACTION ECONOMICS
(1973 dollars for 900 ton and 10,000 ton per day plant)
(6.6×10^5 bbl/yr and 7.3×10^6 bbl/yr oil product)

Economic assumptions	Annual operating expenses (estimated)			
Processed gas is CO, costing \$0.01/lb	Plant size	900 ton/day	10,000 ton/day	
CO cons = 0.5 lb/lb waste	Plant cost	\$20 Million	\$200 Million	
System pressure is 4000 psig	Oil product, (bbl/yr)	6.6×10^5	43.8×10^6	
Process yield is 2 bbl oil/ton dry waste		$\$ \times 10^6$ \$/MBtu	$\$ \times 10^6$	\$/MBtu
Income based on \$4/barrel oil product	Operation & maintenance	1.1 0.279	5.0	0.114
Income from waste disposal is \$5/ton dry	Overhead & taxes	0.2 0.051	2.0	0.496
	Capital charge (20 percent)	4.0 1.015	40.0	0.913
	Total expense	5.3 1.345	47.0	1.073
	(\$ per installed kW _t =	154.	=	137.)

In Situ Coal Gasification

Process description (ref. 17)— The following method appears to represent a feasible and economic way to recover gas in situ from deep coal deposits. The coal beds are first shattered in place with explosives. About 600 tons of coal should be broken by each ton of explosive. Only the region to be processed would be broken in any one explosion; subsequent blasting would be done to ensure that fractures would not reach a previously processed region. Thus, to achieve high efficiency, it would be necessary to drill and blast as large a region as could be processed at one time. In that way, only minimal amounts of coal would be left unreacted.

The second step in this process is to drill access holes to the top and bottom of the shattered region. Some of the explosive loading holes probably could be reused for access and instrumentation if care were taken in stemming them. These access holes would be cased to prevent unwanted water entry.

The third stage involves injecting a small amount of oxygen and starting combustion near the top of the broken zone with a methane flame. When the temperature in the combustion zone reaches about 700°K or higher, the oxygen injection would be replaced mostly with water so that the basic reaction would be between coal and water to produce methane and carbon dioxide. To provide heat to sustain methane production, the oxygen/water ratio should be about unity. Back pressure is built up by restricting the outlet flow until the pressure in the shattered zone is equal to the hydrostatic potential in the coal-bearing zones. In this way, there should be little unwanted water entry or gas escape.

Water injection would be continued from the top and product gases would be withdrawn from the bottom until all the coal in the shattered zone had reacted. In the region below the reaction zone, carbon monoxide is expected to react with water to produce additional methane, carbon dioxide, and heat. Both the reacted and unreacted coal are effective catalysts for the carbon monoxide/water reaction and are also powerful scavengers of sulfur oxides, hydrogen sulfide, and other acid vapors. The product gas is a mixture of methane, carbon dioxide, and water vapor; the latter are removed from the methane by standard procedures yielding a high-quality pipeline gas. Contrasted with surface plant coal gasification processes, this method does not involve mining the coal and does not require a large plant (see fig. 11 and table 6).

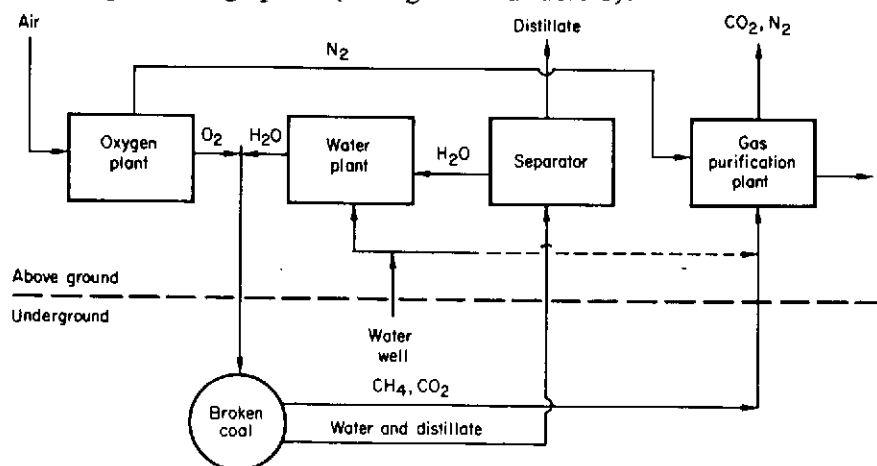


Figure 11.—Flow diagram of in situ coal gasification process.

TABLE 6.— ATOMIC ENERGY COMMISSION IN SITU COAL GASIFICATION ECONOMICS
(1973 dollars for 100×10^9 ft³/yr plant)

Capital investment		Annual operating expense		
Item	Cost \$, Million	Item	Gas cost	
			\$, Million	\$/Million Btu
Coal & land	3.0	Explosives	0.85	0.0085
Oxygen plant	14.0	Oxygen plant operations	7.50	0.0750
Water plant	1.0	Management & contingency	1.25	0.0125
Purification plant	7.4	Water & purification	3.60	0.0360
Miscellaneous & contingency	3.0	Drilling	10.20	0.1020
Drilling equipment	4.2	Insurance & taxes	1.20	0.0120
Develop & start-up	12.4	Capital charge (20%/yr)	9.00	0.0900
Total capital investment	45.0	Total expense	33.60	0.3360
(\$/Installed kW _t =	13.0)			

Coal Gasification

Process description (ref. 15)— The gasification of coal to produce a natural gas substitute involves the reactions of steam hydrogen, carbon monoxide, carbon dioxide, and methane in contact with the bound carbon in coal. All gasification processes contain zones in coal flow sequence which perform the functions of (a) elimination of coal caking, (b) coal devolatilization or distillation to produce some methane, (c) reaction of freshly devolatilized coal with hydrogen, carbon monoxide, and steam to produce additional methane, and (d) preparation from the residual coal char of the carbon monoxide and hydrogen needed to produce methane from the steam-carbon reaction and the water-gas shift reaction. The synthesis gas of carbon monoxide and hydrogen produced in the previous steps is purified and reacted over a catalyst to increase the methane content so that a natural gas substitute with a high heating value (1000 Btu/ft³) is produced.

The objective of all coal gasification processes is to produce clean methane gas at the lowest possible cost with allowance for the value of byproducts. The methods of providing the energy for the processes, the manner in which the materials are reacted, the appropriate temperatures and pressures to secure the desired reaction rates and system composition, the catalytic reactions, and, finally, the manner in which the material flows are the primary technological variables in the production of clean high-Btu gas from coal.

One of the best methods for coal gasification is the BCR Bi-gas process, which uses a vertical-axis, two-stage gasifier operating on either caking or noncaking coal. Pulverized coal is injected with steam into the gasifier where it mixes with synthesis gas, volatilizes, and partially methanates. The product gas-unreacted coal char mixture leaving the gasifier passes through a gasifier where it gasifies with oxygen and steam at high temperatures (2700° to 2800°F). The gas product leaving the top of the gasifier is subsequently purified to remove both acid gas and sulfur and catalytically methanated (see fig. 12 and table 7).

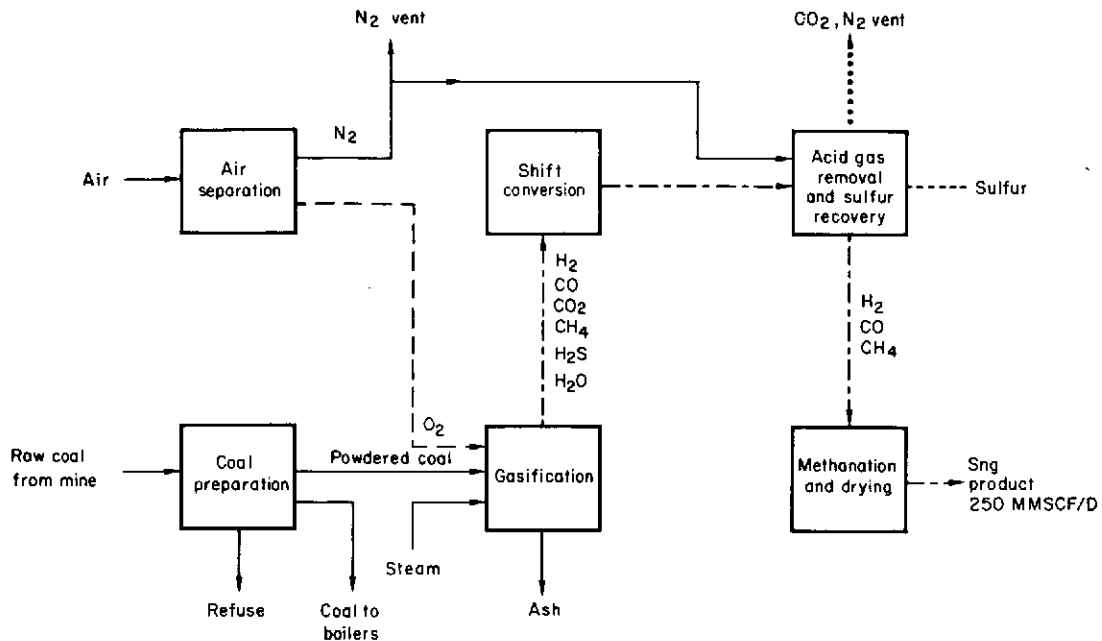


Figure 12.—Flow diagram of the BCR bi-gas coal gasification process.

TABLE 7.—BI-GAS COAL GASIFICATION PROCESS ECONOMICS
(1973 dollars for 91.3×10^9 ft³/yr plant)

Capital investment		Annual operating expenses		
Item	Cost \$, Million	Item	Gas cost	
			\$, Million	\$/Million Btu
Coal preparation & feeding	28.4	Coal @ 15¢/Million Btu	19.0	0.219
Gasification	8.3	Misc. material & supplies	1.7	0.020
Shift conversion	14.1	Operation & maintenance labor	6.3	0.073
Acid gas & sulfur purification	26.4	Overhead & taxes	8.7	0.100
Methanation	13.2	Capital charge (20% of investment)	33.0	0.381
Gas drying	.1	Total expense		
Oxygen plants	29.6	(Coal @ 15¢/Million Btu)	68.7	0.793
Offsites & utilities	~29.7	Total expense		
Engineering & construction fee	7.5	(Coal @ 30¢/Million Btu)	87.7	1.012
Interest during construction (5%)	7.9			
Total capital investment	165.2			
(\$/Installed kW _t =	55.0)			

Solar Algae Gasification

Process description (ref. 18)— Solar energy can be utilized through photosynthesis and bacterial fermentation processes to produce fuel gases, such as methane or hydrogen, to augment the nation's dwindling supplies of natural gas. Fuel gases can be produced from plants grown and harvested on land, in fresh water ponds, or in the ocean.

Studies have been carried out in which *Chlorella* algae grown in sewage ponds and floating water plants (water hyacinth) grown on tropical and semitropical bodies of water have been converted to methane by the fermentation process. Bacterial populations have been developed which permit the fermentation process to be conducted in a marine environment (fig. 13).

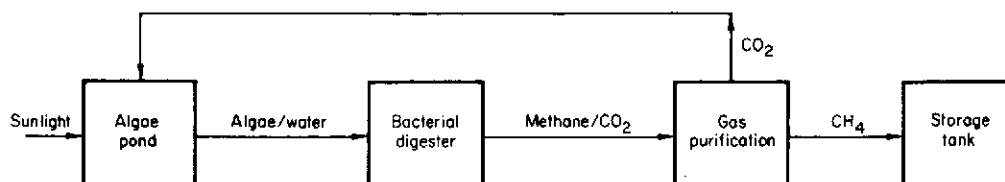


Figure 13.—Flow diagram of the solar algae gasification process.

Most organic materials, including algae, in the presence of some moisture and in the absence of oxygen, are subject to natural fermentation in which a large percentage of the carbon content of the material is converted into a mixture of methane and carbon dioxide. The heating value of this methane is about 1000 Btu/ft³ (the same as for natural gas).

The cultivation of algae may be an attractive proposition even in a very northern state such as Minnesota, where the sunlight is less intense than in the south. Algae grown on only about 0.2 percent of the land in Minnesota could probably produce power through methane generation equal to Minnesota's total 1971 electrical power requirements at peak consumption. Professor A. G. Frederickson of the University of Minnesota postulated the cultivation of *Chlorella* algae in greenhouses and their direct combustion in a conventional pulverized-coal furnace to produce electricity; ash, carbon dioxide, and water would be recycled. It has been suggested that all the world's energy requirements in the year 2000 could be met by combustion of high-energy plants cultivated on only 4 percent of the world's land surface. Only 30 percent of the globe's surface is land; 70 percent is covered with water where high-energy plants can also be cultivated.

TABLE 8.— SOLAR ALGAE GASIFICATION PROCESS ECONOMICS
(1973 dollars for 7.3×10^9 ft³/yr plant)

Capital investment		Annual operating expense		
Item	Cost \$, Million	Item	Gas cost	
			\$, Million	\$/Million Btu
Land area @ \$400/acre	4.0	Operations & maintenance	2.85	0.390
Greenhouse canopy	4.0	Overhead & taxes	2.35	0.322
Collection & digestion	38.0	Capital charge (20% of investment)	9.40	1.288
Methane storage	1.0	Total expense	14.60	2.000
Total capital investment	47.0			
(\$/Installed kW _t =	187.0)			

PROJECTED AIRCRAFT FUEL ECONOMICS

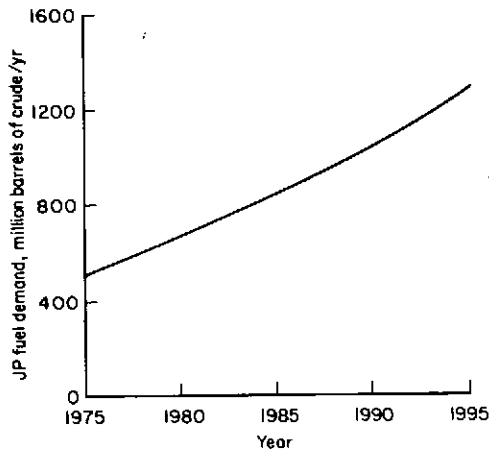


Figure 14.—U. S. JP aircraft fuel demand projection (ref. 4).

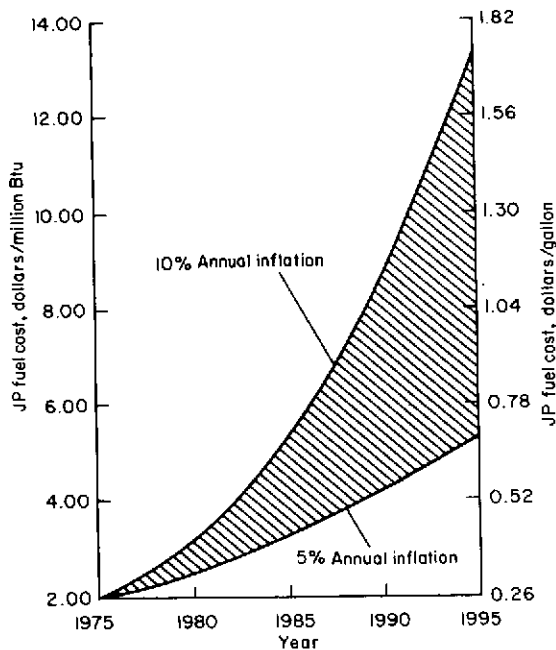


Figure 15.—U. S. JP aircraft fuel cost projection (1975-1995)

The economics of JP (kerosene) aircraft fuel, liquid methane (LCH_4), and liquid hydrogen (LH_2) derived from conventional and unconventional sources are discussed for the period 1975 to 1995.

JP Aircraft Fuel Economics

Before the 1973 fuel crisis, the Bureau of Mines projected the U.S. demand (ref. 23) for JP-type aircraft fuel during the timeframe 1975 to 1995 (fig. 14). Fuel demand (expressed in barrels of crude oil) was estimated to increase from about 500 million barrels per year in 1975 to 1280 million barrels per year in 1995, representing a 5 percent annual exponential growth projection for jet fuel consumption over this timeframe.

Based on fuel properties, source of supply, price, environmental constraints, and aircraft engine design requirements, future supersonic aircraft may require liquefied methane or hydrogen as preferred fuels and hypersonic aircraft will definitely require one of these cryogenic fuels. However, the aforementioned projections of JP fuel demand provide a valid basis for determining aircraft energy (Btu) demand regardless of the type of fuel.

Since fuel costs significantly impact on aircraft direct operating costs (DOC), it is important to provide inflationary projections of these fuel costs which reflect OPEC announced oil pricing policy (OPEC crude oil pricing will directly reflect western inflation).

The projected cost of JP-type fuel (fig. 15) derived from either conventional crude oil (at a 1974 average price of \$9/barrel) or from the liquefaction of domestic coal (hydrogenated coal syn-crude priced at about \$8/barrel) may be expected to increase from about \$2 per M Btu

(\$0.26 per gallon) in 1975 to about \$5.30 per million Btu (\$0.69 per gallon) in 1995, assuming a 5-percent inflationary rate. At 10-percent annual inflation, the price of JP fuel may be expected to increase from \$2 per million Btu (\$0.26 per gallon) in 1975 to about \$13.40 per million Btu (\$1.84 per gallon) in 1995.

Off-shore crude oil reserves— Should offshore, deep-sea oil and gas technology be accelerated to enable the U.S. to tap known major deep-water oil fields (estimated to contain more than 300 billion barrels of oil) in the Gulf of Mexico, the Bering Straits, and the East and West Coast continental slope regions, the U.S. could become independent of foreign oil imports by 1985. Underwater extraction of oil and gas requires specialized and costly manned equipment such as drilling platforms and subsea completion and storage systems. The inherent design of the equipment severely restricts operations during adverse weather conditions. According to the Chase Manhattan Bank, some 50 percent of the ships, barges, jackups, semisubmersibles, and other drilling platforms constructed to this time have been lost primarily because of weather and sea state. The associated capital writeoff has exceeded \$100 million in the past 15 years.

Experience of Phillips Petroleum and others in the North Sea indicates that production wells yielding 10,000 barrels/day or more can be selected from sea-bed sites, with a 20-year life to each well. A 32-well field would yield about 120 million barrels/year. Over a decade, perhaps some 20 such fields could be developed. The cost of developing each field would be \$0.25 billion including drilling of 35 wells (3 dry) at about \$2 million each, completion, production, and storage systems. On the basis of \$1 per barrel for operations and maintenance (\$120 million per year) and 20-percent capital recovery (\$50 million per year), the annual net production costs would total about \$1.50 per barrel of crude. Capital cost uncertainties associated with deep ocean oil recovery could double this figure to about \$2.90 per barrel (fig. 16). This variance in the estimated cost of producing oil at 3000-ft sea depths is a function of extending present 400-ft offshore oil technology into much greater sea depths. Even so, the promise of oil at \$2.90 per barrel is substantially below current imported crude prices of \$9 per barrel.

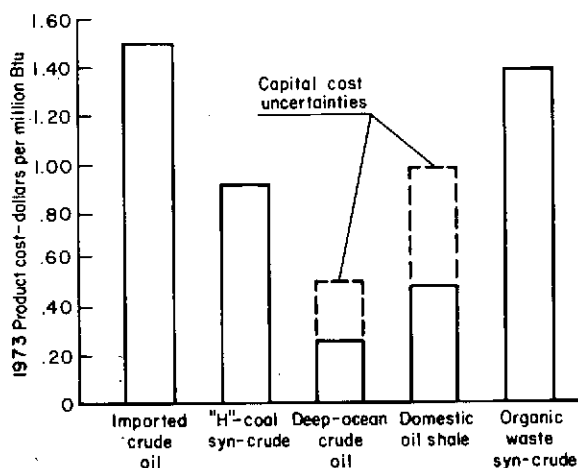


Figure 16.—Product costs for U. S. alternative oil processes (1 U. S. barrel = 5.8 million Btu).

Economics of JP fuel from oil shale— JP fuel derived from oil shale retorting and subsequent crude processing may cost from \$0.965 to \$1.45 per million Btu (\$0.125 to \$0.19 per gallon), depending on the actual capital and environmental costs associated with an optimized oil-shale processing plant. This product cost is considerably less than JP fuel derived from either conventional imported crude oil or coal syn-crude; however, even the economically recoverable domestic oil shale reserves estimated at 600 billion barrels of oil (3500×10^{15} Btu) are inadequate to meet long-term U.S. demand for liquid fuels at the 1973 consumption rates, (less than 100-year supply).

Economics of JP fuel from organic waste syn-crude— The organic waste liquefaction process described earlier is potentially capable of supplying half the U. S. low-sulfur fuel oil demand by primary electric utilities by 1980. The fuel oil product of organic waste conversion, costing

\$1.38 per million Btu (\$8 per barrel), may be upgraded to a satisfactory JP-type aircraft fuel by catalytic hydrogenation in existing refineries at a cost of about \$0.96 per million Btu, providing JP fuel at about \$2.34 per million or \$0.30 per gallon (f.o.b. refinery, untaxed, 1973 dollars).

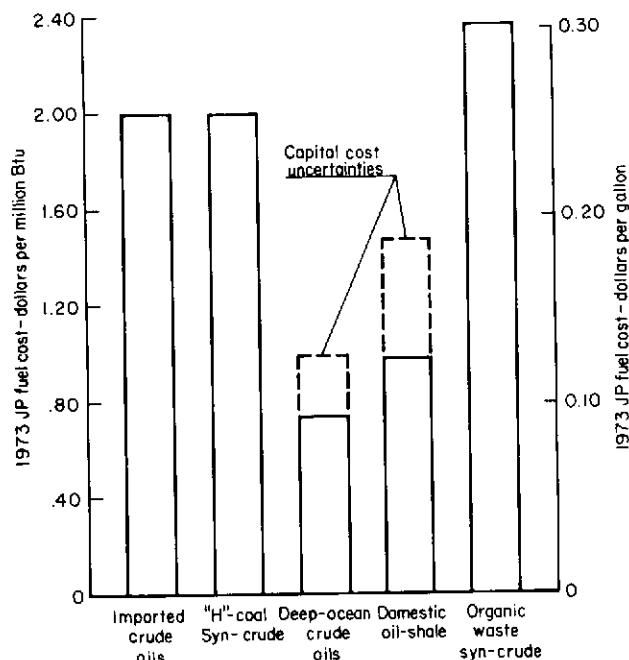


Figure 17.—Cost of JP aircraft fuel from alternative oil sources (1973 dollars)

JP fuel cost summary— 1973 JP fuel costs from the aforementioned alternative oil processes are summarized in figure 17. The deep-ocean and shale oil processes appear to be the most economic; however, both processes are currently entering pilot development and therefore are subject to the greatest uncertainty in actual capital investment (represented by dotted cost bars) for full-scale operations.

Liquid Methane Aircraft Fuel Economics

Liquid methane as an aircraft turbine engine fuel offers many advantages (refs. 19 and 20) over conventional JP fuel. Among these are lower fuel cost, improved handling and storage safety due to no toxicity, rapid evaporation and higher ignition temperature, and much lower decomposition product (five orders of magnitude). The cooling values of both liquid methane and hydrogen are essential to advanced aircraft performance at higher Mach number (about 3.5); however, the complexity and substantial related costs of storing and handling cryogenic fuels must be considered in any analysis of future aircraft operating costs. These costs are not addressed here.

The 1973-74 costs of methane gas derived from domestic natural gas, from imported liquefied natural gas (LNG), from coal gasification (in situ and Bi-gas processes), and from the fermentation of algae (solar process) are depicted in figure 18. Unfortunately, the most economic process requires domestic natural gas, which is in increasing short supply; one would expect this cost to increase significantly in the near future if natural gas prices remain unregulated. Volumetric aircraft fuel storage considerations require the liquefaction of gaseous fuels. Liquefaction of methane gas, regardless of the source, adds about \$0.80 per million Btu to the base cost of this fuel (included in the liquid methane cost summary in fig. 18).

The projected cost of liquid methane, derived from the Bi-gas coal gasification process, at 5- and 10-percent annual inflation over the timeframe 1975-1995, is shown in figure 19. This source of liquid methane was selected on the basis of long-term resource availability. Of significance is the

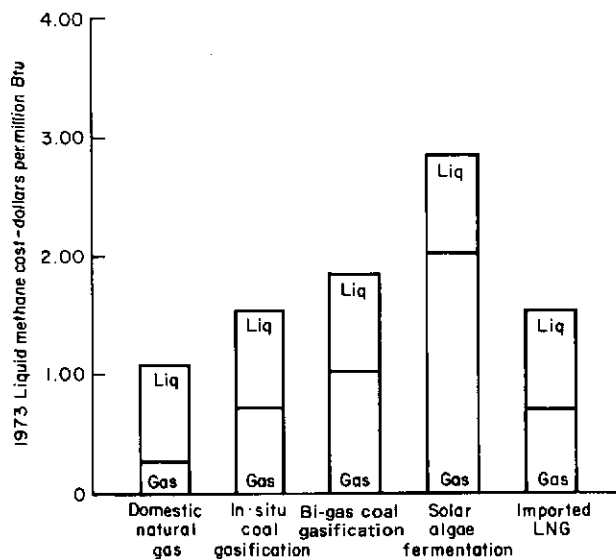


Figure 18.—Cost of liquid methane aircraft fuel from alternative gas sources (1973 dollars)

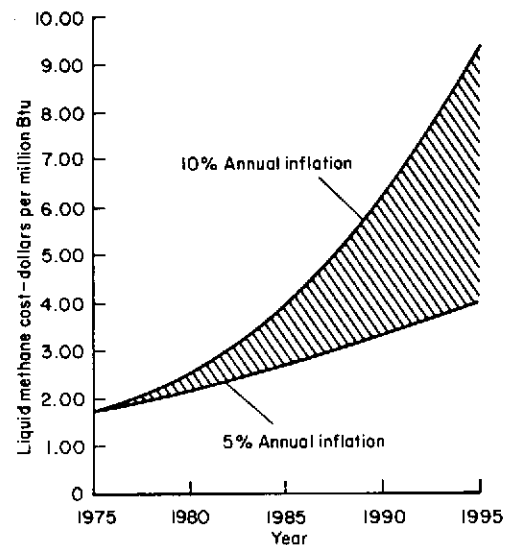


Figure 19.—U. S. liquid methane cost projection (1975-1995) (methane source: coal gasification)

comparative projected cost of liquid methane and JP fuel derived from domestic coal — liquid methane currently costs 10 percent less than JP fuel, it provides essentially the same amount of energy (about 20,000 Btu/lb), and it is environmentally cleaner burning. Further, the logistics of gaseous methane pipeline distribution and delivery at airport-sited liquefaction units favor implementation of this fuel for aircraft.

Liquid Hydrogen (LH₂) Aircraft Fuel Economics

As with methane, volumetric fuel storage constraints in aircraft demand that gaseous hydrogen be liquefied. Regardless of production source, the energy and economic cost of hydrogen gas liquefaction is substantial (refs. 26-28).

About 20,000 Btu (5.8 kWh) of energy are required to liquefy 1 lb of hydrogen. Before 1970, low-cost (2 mills/kWh), off-peak power was available for this liquefaction process. Current electricity costs are approaching 15 to 20 mills/kWh, a tenfold increase driven principally by environmental capital and operating costs. These costs include nuclear powerplant siting and safety requirements, fossil-fuel powerplant air-pollution controls, and fossil fuel cost increases. The resultant cost of hydrogen liquefaction has increased from less than \$0.02/lb (\$0.36 per million Btu) before 1970 to at least \$0.14/lb (\$2.45 per million Btu) in 1974.

Methane steam reforming LH₂ economics— The actual 1971 price of LH₂ from methane steam reforming ranged from \$0.10 to \$0.18/lb (\$1.80 to \$3.24 per million Btu) (personal communication with Robert Harwood of NASA Headquarters). Hydrogen prices from this process are highly dependent on methane feedstock prices, plant size, capacity utilization, power costs, and the operating life of the plant.

Regulatory price controls were lifted in 1973 on all new wellhead domestic gas. Currently, the average wellhead domestic gas price is about \$0.25 per million Btu versus coal at \$0.30 per million Btu and domestic oil at about \$1.12 per million Btu. It is anticipated that domestic natural gas feedstock prices will at least triple in the near future, resulting in steam reformed LH_2 prices in the range of \$0.225/lb (\$4.05 per million Btu).

Coal gasification LH_2 economics— Pilot coal gasification processes directly yield hydrogen gas, which is subsequently methanated to methane gas. Estimates of the intermediate hydrogen gas costs are relatively uncertain at this time because large-scale pilot facilities have not been built and operationally tested. However, these costs may be synthesized from available small-scale pilot plant cost data. On this basis, gaseous hydrogen from direct coal gasification would cost about \$0.05/lb (\$0.95 per million Btu); LH_2 from this process may be expected to cost about \$0.19/lb (\$3.40 per million Btu). Thus, the cost of coal-derived LH_2 would appear to be more than competitive with the cost of natural-gas-derived LH_2 and offers an almost unlimited source of supply.

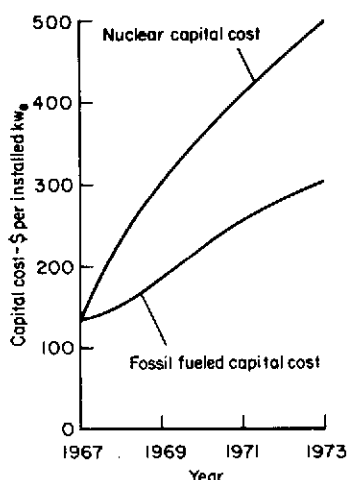


Figure 20.—Nuclear- and fossil-fueled powerplant capital costs.

Electrolytic LH_2 economics (ref. 24)— Present electrolytic cells require about 25 kWh to produce 1 lb of hydrogen gas from the dissociation of water. It is estimated by the electrochemical industry that cell efficiencies will be improved shortly so that only 20 kWh will be required per pound of hydrogen.

The cost of conventional fossil-fueled power is approaching 15 mills/kWh and light water nuclear reactor power costs are currently about 19 mills/kWh. As mentioned earlier, environmental requirements have tripled the associated powerplant capital costs since 1967 (fig. 20).

The resultant effects of increased power costs on the 1974 cost of electrolytic production and liquefaction of hydrogen are calculated in table 9.

TABLE 9.— COSTS OF ELECTROLYTIC HYDROGEN PRODUCTION

Process element	Unit costs	
	Fossil fuel power (15 mills/kWh)	Nuclear power (19 mills/kWh)
Electrolysis (mills/kWh \times 20kWh/lb H_2)	\$0.30	\$0.38
Liquefaction	0.14	0.14
Total 1974 cost/lb LH_2	\$0.44	\$0.52
Equiv. LH_2 cost/million Btu	\$7.85	\$9.25

LH₂ fuel cost summary— The 1973-74 costs of liquid hydrogen derived from methane steam reforming, direct coal gasification, and fossil fuel and nuclear electrolysis of water are compared in figure 21. The least expensive large-scale LH₂ production process at this time is clearly liquefaction of hydrogen derived from direct coal gasification at \$0.19/lb LH₂ (\$3.40 per million Btu). An obvious economic need is to develop a more efficient hydrogen liquefaction process since this process currently accounts for 72 percent of the 1974 total coal gasification LH₂ production cost.

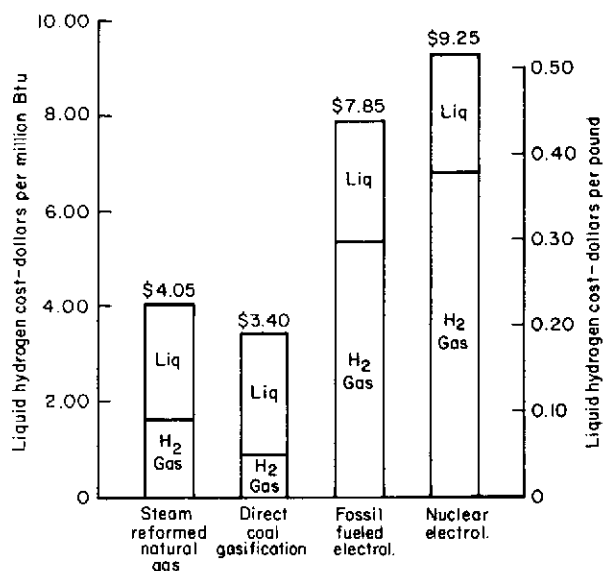


Figure 21.—Alternative liquid hydrogen processing costs (1973 dollars).

CONCLUDING REMARKS

This study examined the future of U.S. transportation fuels and attendant economics for the period 1975-1995. Although the economics of transportation fuel alternatives were presented as summarized in figure 22, it was not the intent of this report to advocate a future fuels policy. However, this study does provide an opportunity to assess the general prospect of future energy independence for the United States.

The results of this study clearly indicate that, from a resource and sociotechnical point of view, the United States can achieve energy independence by 1985 and can maintain this posture throughout the remainder of the century if the U.S. pursues a unified energy policy that enables the responsible technological development and exploitation of its vast coal, shale oil, offshore oil, and other energy resources.

The technological capability currently exists for economically converting these resources into clean-burning conventional and unconventional portable fuels in ample volumes to support the continued growth of the U.S. economy.

The availability of capital for future domestic energy resource development and production appears to be the dominant constraint or barrier to the effective and orderly implementation of U.S. energy independence, the realization of continued economic growth, and the quality of life in the U.S.

The United States must adopt unusual discipline and ingenious incentives to stimulate its energy industry to attain the \$100 billion/yr capitalization over the next decade required to meet

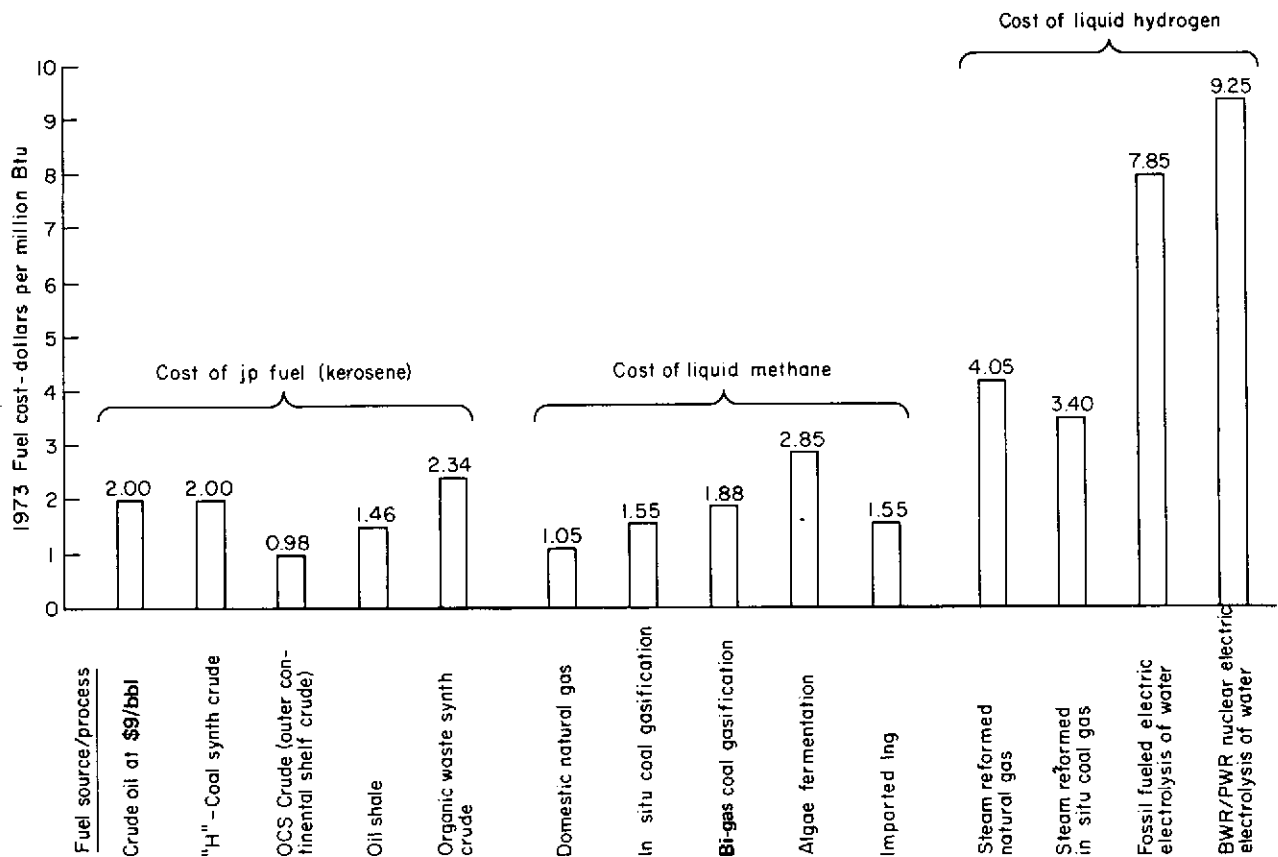


Figure 22.—Cost comparison of United States alternative transportation fuels (1973 dollars)

the most conservative demand projections in the face of continuing massive capital migration for energy importation.

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Moffett Field, Calif. 94035, January 1975

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